DIRECT TESTIMONY AND EXHIBIT

OF

BRIAN HORII

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2019-184-E

IN RE: SOUTH CAROLINA ENERGY FREEDOM ACT (H.3659) PROCEEDING TO ESTABLISH DOMINION ENERGY SOUTH CAROLINA, INCORPORATED'S STANDARD OFFER, AVOIDED COST METHODOLOGIES, FORM CONTRACT POWER PURCHASE AGREEMENTS, COMMITMENT TO SELL FORMS, AND ANY OTHER TERMS OR CONDITIONS NECESSARY (INCLUDES SMALL POWER PRODUCERS AS DEFINED IN 16 UNITED STATES CODE 796, AS AMENDED) – S.C. CODE ANN. SECTION 58-41-20(A)

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"). Founded in 1989, E3 is an energy consulting firm with expertise in helping utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have over thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1. My prior work experience in this subject matter includes the following:

- Developed the methodology for calculating avoided costs used by the California Public Utilities Commission for evaluation of Distributed Energy Resources ("DER") since 2004;
- Developed the methodology for calculating avoided costs used by the California Energy Commission for evaluation of building energy programs;
- Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and PSI Energy;
- Provided review of, and corrections to, PG&E avoided cost models used in their general electric rate case;

- Developed the integrated planning model used by Con Edison and Orange and Rockland Utilities to determine least cost DER supply plans for their network systems;
- Developed the hourly generation dispatch model used by El Paso Electric Company to evaluate the marginal cost impacts of their off-system sales and purchases;
- Produced publicly vetted tools used in California for the evaluation of energy efficiency programs, distributed generation, demand response, and storage programs;
- Analyzed the cost impacts of electricity generation market restructuring in Alaska, Canada, and China; and
- Developed the "Public Tool" used by California stakeholders to evaluate Net Energy Metering ("NEM") program revisions in California.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes, I previously testified before this Commission on behalf of the Office of Regulatory Staff ("ORS") in Docket Nos. 2017-2-E and 2018-2-E. I also prepared and filed direct and surrebuttal testimony in Docket No. 2019-2-E.

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to conduct analysis, review, and develop recommendations regarding the following filings by Dominion Energy South Carolina, Inc. ("DESC" or the "Company") in this docket:

1) Standard offer;

2) Avoided cost methodologies;

3) Form contract power purchase agreements ("PPA");

4) Commitment to sell forms;

5) Any other terms or conditions necessary to implement Section 58-41-20(A) of the South Carolina Energy Freedom Act ("Act 62" or the "Act");

6) Confirm the avoided cost methodology meets the Public Utility Regulatory Policies Act of 1978 ("PURPA") requirements;

7) Verify the avoided energy and capacity cost rates requested by the Company are a reasonable result of the Company's avoided cost methodology; and

8) Verify the solar variable integration charge ("VIC") requested by the Company is reasonable and quantified correctly.

ORS also retained E3 to conduct an analysis of DESC's Value of DER calculation to:

1) Verify the Company populated each of the eleven (11) categories according to the methodology established in Order No. 2015-194;

2) Confirm, for each category with a zero (0) value, that the Company does not have sufficient capability to accurately quantify those costs or benefits to the utility system; and

3) Verify, for each category with a value other than zero (0), that the value assigned is a result of the Company's ability to accurately quantify those costs or benefits to the utility's system.

Q. UNDER ACT 62, WHAT ELEMENTS INFORMED YOUR REVIEW OF THE COMPANY'S FILINGS?

A. My review and resulting recommendations are based on standard industry principles in establishing avoided costs for electrical utilities and relied on the guidance provided in Section 58-41-20(A) of Act 62. Specifically,

> [a]ny decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the FERC's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public.

In addition, ORS relied on Section 16 of the Act which states:

> Notwithstanding another provision of this act, or another provision of law, no costs or expenses incurred nor any payments made by the electric utility in compliance or in accordance with this act must be included in the electrical utility's rates or otherwise borne by the general body of South Carolina retail customers of the electrical utility without an affirmative finding supported by the preponderance of evidence of record and conclusion in a written order by the Public Service Commission that such expense, cost or payment was reasonable and prudent and made in the best interest of the electrical utility's general body of customers.

Q. ARE THE REQUIREMENTS OF ACT 62 CONSISTENT WITH PURPA?

A. Yes. Consistent with a federal statutory mandate, PURPA requires the Federal Energy Regulatory Commission ("FERC") to promulgate rules, that ensure utilities offer avoided cost rates which are just and reasonable to electric consumers and in the public interest, and not discriminatory against qualifying small power producers. Act 62 specifies that electric utilities offer certain contract terms to small power producers, subject to approval by this Commission. Under current FERC regulations, state regulatory authorities such as this Commission have broad latitude in determining state specific PURPA policies and I believe the requirements of Act 62 are consistent with PURPA and implementing regulations promulgated by the FERC.

Q. IN YOUR OPINION, WERE THE COMPANY'S FILINGS IN THIS DOCKET REASONABLY TRANSPARENT FOR YOUR INDEPENDENT REVIEW AND ANALYSIS?

A. Yes. The Company provided data responses and supporting information to their filings that allowed me to conduct my analysis, assess the reasonableness of their proposals, and develop recommendations regarding the implementation of Act 62. In addition, I was able to make important improvements to the Company's assumptions and flow my changes through the Company's models to update the avoided energy and capacity rates for all Qualifying Facilities ("QFs") and the VIC for solar QFs.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR COMMISSION CONSIDERATION TO IMPROVE TRANSPARENCY IN FUTURE PROCEEDINGS?

A. Yes. I do understand the time constraints in implementation of the Act. While I was able to do a quick assessment and identify clear issues with some of the Company's assumptions, future proceedings would benefit from an expansion of time for the filing of direct and rebuttal testimonies. For comparison, the proceedings in California that determine avoided costs and ratemaking, parties are provided with approximately four (4) months to prepare testimony after the utility application is filed, with rebuttal testimony from all parties due about three (3) months later. This expanded timeframe allows parties adequate time to conduct analysis, develop positions, allow the utility ample time to respond to data requests, and provides all parties with more time to potentially settle any emerging issues prior to the evidentiary hearing.

Q. BRIEFLY DESCRIBE THE REQUIREMENTS OF PURPA AND HOW THEY RELATE TO THE RATE PR-1 AND RATE PR-STANDARD OFFER ("STANDARD OFFER") PROPOSED BY THE COMPANY.

A. In 1978, as part of the National Energy Act, Congress passed PURPA. The policy was designed, among other things, to encourage conservation of electric energy, increase efficiency in use of facilities and resources by utilities, and produce more equitable retail rates for electric consumers.

To help accomplish PURPA goals, a special class of generating facilities called QFs was established. QFs receive special rate and regulatory treatments, including the ability to sell energy and capacity to electric utilities. All electric utilities, regardless of ownership structure, must purchase energy and/or capacity from, interconnect to, and sell back-up power to a QF. This obligation is waived if the QF has non-discriminatory access to competitive wholesale energy and long-term capacity markets.

In DESC's service territory, Small Power Producers and Cogenerators that are designated as QFs and have capacity less than or equal to 100 kilowatts ("kW") are compensated under Rate PR-1. QFs with capacity greater than 100 kW and less than or equal to 2 megawatts ("MW") are compensated under the Company's proposed Standard Offer. I will address my analysis and calculations of proposed rates and charges later in my direct testimony.

Q. HOW WILL QFS LARGER THAN 2 MW BE COMPENSATED BY DESC?

A. DESC has historically compensated QFs larger than 100 kW but less than or equal to 80 MW under the Rate PR-2 tariff. In this docket, DESC proposes to withdraw and terminate its existing Rate PR-2 tariff effective as of the last billing cycle of April 2019.

QFs larger than 2 MW will now be compensated under form contract PPAs individually negotiated between DESC and the QF. The negotiated rates will be based on the Company's Commission approved avoided costs and will be filed with the Commission pursuant to Act 62.

I. Variable Integration Charge Analysis, Discussion, and Recommendations

Q. DOES INTEGRATING RENEWABLE GENERATION CREATE ADDITIONAL COSTS FOR UTILITIES?

A. Yes. E3 conducted extensive work in California and Hawaii where renewable generation comprises a large portion of generation resources. In our own modeling, E3 has seen that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. The cost impact can include higher start-up costs, fuel costs, and O&M costs resulting from resources operating at levels below their maximum efficiency to allow upward headroom to ramp up output. Costs can also increase for additional generation plant required to provide additional flexible capacity.

Q. PLEASE EXPLAIN HOW DESC INTENDS TO RECOVER INTEGRATION COSTS FROM QFS.

A. The Company intends to recover integration charges from QFs in two (2) different ways. For QFs with a fully executed PPA, DESC proposes to collect the VIC on a prospective basis until the end of the PPA term (Folsom, p. 15). For all other QFs, the Company included solar integration costs as a reduction to avoided energy and any QF commitments after the Commission's approval of Rate PR-1 and Standard Offer rates will include integration costs.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE COSTS FOR SOLAR INTEGRATION IN AVOIDED ENERGY CALCULATIONS?

A. No. DESC has created a confusing case where integration costs are calculated in one manner by Navigant for the VIC and calculated in a different way using different assumptions for Rate PR-1 and Standard Offer rates. For Rate PR-1 and Standard Offer rates, DESC proposed to reflect integration costs through a reduction in the avoided energy rates provided to solar QFs. In the next section of my direct testimony, I discuss the flaws of the Company's proposal for integration costs for Rate PR-1 and Standard Offer rates and recommend therein that integration-related costs not be adopted for Rate PR-1 and Standard Offer rates.

Q. BRIEFLY EXPLAIN THE COMPANY'S METHODOLOGY FOR CALCULATING THE VIC.

A. First, the Company estimates the additional amount of operating reserves that should be carried because of the output uncertainty of solar generators on the DESC system. Next, the Company runs two PROMOD production simulations --- one with a normal operating reserve requirement, and a second with a higher than normal operating reserve requirement. The VIC is the amount of increased operating costs in the higher operating reserve simulation.

The Company performed this analysis for two (2) scenarios of solar penetration on the DESC system and calculated the proposed VIC based on a blend of the additional costs from each scenario.

Q. DO YOU AGREE WITH THE COMPANY'S METHODOLOGY TO CALCULATE RENEWABLE INTEGRATION COSTS?

A. Yes. I have reviewed Company witness Tanner's (or "Navigant") Exhibit No._(MWT-2), Cost of Variable Integration ("Integration Study") and find the overall concepts of the methodology used in the Integration Study to be reasonable.

Q. WHAT ASSUMPTIONS AND INPUTS DID THE COMPANY USE IN CALCULATING THE VIC?

A. DESC simulates operating costs using standard PROMOD representations of the DESC system. The unique aspect of the Company's analysis is (1) the estimation of the maximum potential shortfall of actual solar output compared to forecast levels, based on National Renewable Energy Laboratory ("NREL") data; and (2) the use of increased annual operating reserve requirements attributed to the maximum potential shortfall of actual solar output.

The estimated increase in the operating reserve requirement drives the difference in costs between the business-as-usual and the solar integration cases (the case with the higher operating reserve requirement). The more additional reserves, the higher the estimated VIC. It is therefore important not to overestimate the amount of additional reserves required in order to prevent overestimation of the costs of solar integration.

Q. DOES THE COMPANY'S PROPOSED VIC REASONABLY ESTIMATE RENEWABLE INTEGRATION COSTS?

A. No. The assumptions used by Navigant overstate the risks of uncertain variable generation to the Company which inflates the resulting variable integration costs. I propose a more balanced approach that results in a reasonable value for the VIC.

Q. PROVIDE A SUMMARY OF YOUR OBSERVATIONS RELATED TO THE COMPANY'S PROPOSED VIC.

A. I find the Company overestimated the cost of integrating solar resources through the following erroneous methods and assumptions:

1) The Company failed to conduct an analysis that balances risks and costs to determine the additional amount of operating reserves that would need to be carried due the existence of variable solar resources on the system;
2) The Company is unreasonably risk averse in its determination of the amount of additional operating reserves due to potential solar forecast error; and
3) The Integration Study overstates operating reserves needed by holding reserve levels constant over each day.

Q. IS IT REASONABLE FOR THE COMPANY TO REQUIRE ADDITIONAL OPERATING RESERVES TO ADDRESS THE POSSIBILITY THAT RENEWABLE GENERATION OUTPUT WILL BE LOWER THAN FORECASTED?

A. Yes. The function of operating reserves is to allow the system operator(s) to quickly respond to unexpected changes in generation output or deviations in customer demand. Existing levels of operating reserves are informed by decades of experience with the electrical grid. However, the increased penetration of solar generation on the system introduces a new type of resource to the system and increasing operating reserves are one method for addressing the uncontrolled variation in solar output. The higher the operating reserves, the lower the risk of not having enough generation available to meet customer demands. This energy shortfall is referred to as unserved energy. In theory, the level of operating reserves is a balance of the higher cost of providing those reserves with the reduced risk of unserved energy.

Q. DOES THE INTEGRATION STUDY (TANNER, EXHIBIT NO._(MWT-2)) USE A BALANCED APPROACH TO FORECAST OPERATING RESERVES?

A. Not in my opinion. Managing a utility system has always required the balance of risks and costs. It is widely known that a perfectly reliable system would be cost prohibitive, so an evaluation of risk versus cost is necessary to arrive at a system that meets the needs of its customers. For example, because of the high costs of electricity outages in Manhattan (think of the risk for New Yorkers stuck in elevators in the highly vertical city, and the strain on first responders), Con Edison builds and operates for extremely high reliability, but Con Edison customers also bear some of the highest electric costs in the nation.

When evaluating the need for additional operating reserves for DESC, Navigant does not perform any balance of risk and cost in the Integration Study. Nor does the Integration Study seek to maintain a specific level of risk previously deemed reasonable. Instead, the Integration Study assumes that solar generation will drop from its forecast level to its minimum output level based on forecast error information from the NREL. This assumption essentially places an infinite value on the cost of unserved energy, and results in integration costs that are likely higher than what would have been estimated had an actual risk-based analysis been performed by DESC. The balancing of costs and risks is a fundamental principle of electricity resource planning. However, it seems that because the VIC would be imposed entirely on solar resources, this fundamental principle has been ignored by the Company.

Q. WHY DO YOU CONSIDER THE INTEGRATION STUDY ASSUMPTIONS TO BE HIGHLY RISK AVERSE?

A. The risk of not having enough power to serve customer needs depends on the combined variations in both customer demand and generation plants. By considering only the generation side of the risk equation, DESC is modeling an excessive amount of additional reserve requirements to mitigate the Company's risk.

The Integration Study models reserve requirements by adding "solar forecast error" to the normal utility reserve requirement. The solar forecast error is the <u>maximum</u> drop in output from the aggregate solar fleet, based on the forecasted output of the solar fleet. By using this maximum drop in output, the Integration Study estimates the cost of increased operating reserves based on the assumption that the solar output will be at the lowest level. This assumption is flawed because it does not reflect the actual distribution of potential solar output or the possibility that customer demand may be lower than expected which could lower the need for additional reserves.

Q. HAS DESC PROVIDED THE INFORMATION NECESSARY FOR YOU TO FULLY EVALUATE A MORE REASONED APPROACH?

A. Yes. To evaluate a more reasonable level of operating reserves, I use 1) the Solar Forecast Uncertainty, and 2) the Conditional Probability of Solar Variability, both from the Integration Study.

Q. WHAT MODIFICATIONS DO YOU RECOMMEND REGARDING THE SOLAR FORECAST UNCERTAINTY?

A. The Integration Study (Page 23) is driven by the assumed solar forecast uncertainty from Table 1 below.

Table 1: Integration Study Maximum Drop in Generation

Table 9. Solar Forecast Uncertainty

Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation
< 40%	75%
40% - 50%	65%
50% - 55%	45%
> 55%	25%

These values are derived from estimates of the probabilities of solar output drops, as reproduced in Table 2 below. The Integration Study simply looked at a Forecast Generation row and used the Drop value (the column heading) for the furthest left non-zero value on the table. For example, for the 50-55% expected generation level, the Integration Study used the 45% Drop column shown for the 55% row since that is the leftmost column with a non-zero probability.

Table 2: Integration Study Conditional Probability of Solar Variability (circles added)

Table 8. Conditional Probability of Solar Variability

Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
20%	0%	1%	4%	6%	9%	16%	23%	33%
25%	1%	2%	4%	5%	8%	13%	21%	33%
30%	1%	2%	3%	6%	9%	13%	22%	34%
35%	1%	2%	4%	7%	11%	16%	22%	33%
40%	1%	1%	2%	3%	5%	9%	16%	27%
45%	0%	1%	1%	2%	4%	8%	13%	22%
50%	0%	1%	1%	2%	4%	7%	12%	25%
55%	0%	0%	0%	1%	1%	2%	6%	16%
60%	0%	0%	0%	0%	0%	1%	3%	11%
65%	0%	0%	0%	0%	0%	1%	3%	5%
70%	0%	0%	0%	0%	0%	0%	2%	5%

Since DESC must maintain self-sufficiency, it is necessary to plan for the worst case drops in solar generation. Table 9 gives the solar generation at risk that is used in this study. In each hour, the amount of solar forecasted to generate is calculated and this table is used to calculate the potential drop in solar that the system may need to respond to.

We can evaluate the effect of DESC taking a more balanced approach and exclude the extreme points on the probability distribution. To do that I use that same Table 2 above and move to the right to exclude no more than 2% of the probability of outage for a forecasted generation level. For the 50-55% expected generation level, the solar risk moves from the “>45%” column to the “> 25%” column, as shown below in Table 3.

Table 3: Conditional Probability of Solar Variability (with less Risk Aversion)

Table 8. Conditional Probability of Solar Variability

Forecasted Generation	>75% Drop	>65% Drop	>55% Drop	>45% Drop	>35% Drop	>25% Drop	>15% Drop	>5% Drop
20%	0%	1%	4%	6%	9%	16%	23%	33%
25%	1%	2%	4%	5%	8%	13%	21%	33%
30%	1%	2%	3%	6%	9%	13%	22%	34%
35%	1%	2%	4%	7%	11%	16%	22%	33%
40%	1%	1%	2%	3%	5%	9%	16%	27%
45%	0%	1%	1%	2%	4%	8%	13%	22%
50%	0%	1%	1%	2%	4%	7%	12%	25%
55%	0%	0%	0%	1%	1%	2%	6%	16%
60%	0%	0%	0%	0%	0%	1%	3%	11%
65%	0%	0%	0%	0%	0%	1%	3%	5%
70%	0%	0%	0%	0%	0%	0%	2%	5%

Since DESC must maintain self-sufficiency, it is necessary to plan for the worst case drops in solar generation. Table 9 gives the solar generation at risk that is used in this study. In each hour, the amount of solar forecasted to generate is calculated and this table is used to calculate the potential drop in solar that the system may need to respond to.

Q. WHAT IS THE OUTCOME OF YOUR CALCULATION?

A. Repeating the exercise discussed above for all four (4) categories of forecasted generation output yields the revisions in Table 4 below, which summarizes the reduction in reserve requirements. Column C shows the adjusted Drop values, and Column D shows the percentage reduction in forecast uncertainty for each expected generation output category, which equates to a 36.2% weighted average reduction in forecast uncertainty that needs to be addressed with increased reserves.

Table 4: Reduction in Incremental Reserve Requirements from Less Risk Aversion

A	B	C	D	E	F
Expected Generation as % of Installed Nameplate Facility Rating	Maximum Drop in Generation	Drop w/o Lowest 2%	% Reduction in Forecast Uncertainty	% Solar Output in Category	Weighted Average Reduction
MWT-2, Table 9	*MWT-2, Table 9*	*Table 2*	*(1-C /B)*	*NREL Solar Data*	*(Sum of D * E)*
<40%	75%	55%	26.7%	22%	
40% - 50%	65%	45%	30.8%	15%	
50% - 55%	45%	25%	44.4%	14%	
> 55%	*25%*	*15%*	*40.0%*	*48%*	
Average					**36.2%**

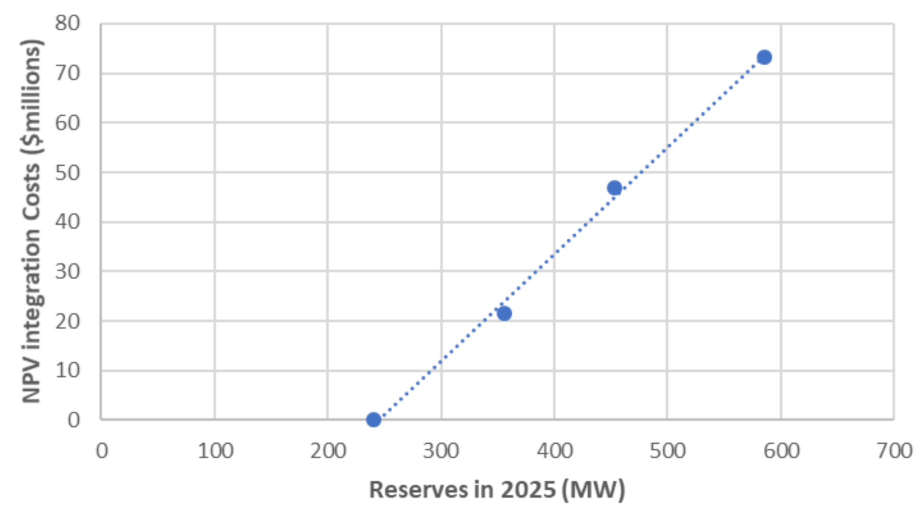
Q. EXPLAIN WHY YOUR CALCULATION IS MORE REASONABLE THAN THE CALCULATION INCLUDED IN THE INTEGRATION STUDY.

A. My approach is reasonable because it provides a balanced assessment of the risk of solar output forecast error. By not requiring additional operating reserves to cover the maximum potential solar output drop and adjusting the solar output drop to a reasonable 98th percentile drop, my results are non-discriminatory towards QFs, and will not set a precedent for unfair treatment of such resources in the future.

Q. HOW DOES THE REDUCTION IN FORECAST UNCERTAINTY TRANSLATE TO A REDUCTION IN INTEGRATION COSTS?

A. The forecast uncertainty drives the amount of additional reserves modeled by DESC. Since the forecast uncertainty that needs to be accounted for is 36.2% less than modeled, the amount of additional reserves for solar should also be 36.2% less than estimated. To translate the reserve change to a cost impact, I simply referred to the Integration Study's estimates of integration costs by reserve level, represented below in Figure 1. The figure shows that the integration costs can be estimated as a simple linear relationship to additional reserve levels. Because of this linear relationship, the 36.2% reduction in forecast uncertainty results in a 36.2% reduction in integration costs.

Figure 1: Relationship between Reserves and Total Integration Costs



Costs from MWT-2, Table 13; Reserves from MWT-2, Table 12

Q. WHAT IS THE IMPACT TO THE COMPANY'S PROPOSED INTEGRATION COSTS AFTER APPLYING THE 36.2% REDUCTION OF FORECAST UNCERTAINTY?

A. DESC's proposed integration cost of $4.14/MWh (Tanner, p. 21) is really a net integration cost, as it has been reduced by the cost of Energy not Served and Reserves Deficit costs to avoid the double counting of those costs with other values in Rate PR-1 and Rate PR-Standard Offer solar QF avoided costs, as described in the Integration Study (p. 29). To calculate the corresponding adjusted net integration cost, I first calculated the

DESC gross integration cost by adding back $0.96/MWh from the Integration Study (p. 29) to the $4.14/MWh DESC VIC value. I then adjusted the gross integration cost down by my 36.2% and subtracted the $0.96/MWh value to arrive at a net adjusted integration cost of $2.29/MWh. These calculations are shown below in Table 5.

Table 5: Adjusted Net Integration Cost

Line	Item	Value	Source or Formula
1	Navigant Integration Cost ($/MWh)	4.14	(Tanner, p. 20)
2	Energy Not Served and Reserve Deficit Costs ($/MWh)	0.96	(MWT-2, p. 29)
3	Unadjusted Integration Cost	5.10	(L1 + L2)
4	Reduction for Lower Risk Aversion	36.20%	Horii, Table 4
5	Adjusted Total Integration Cost ($/MWh)	3.25	(L3*(1-L4))
6	**Adjusted Net Integration Cost ($/MWh)**	**2.29**	**(L5 - L2)**

Q. YOUR RECOMMENDATION IS BASED ON A SIMPLE ADJUSTMENT FOR RISK. HAVE YOU BENCHMARKED YOUR ESTIMATE AGAINST OTHER MORE RIGOROUS ANALYSES?

A. Yes, I compared my adjusted value to the values proposed by Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") in their 2019 avoided cost dockets (2019-185-E and 2019-186-E, respectively). The DEC and DEP values are compared to DESC's proposal and E3's recommendation in Figure 2 below. As with the prior comparison to DEC and DEP, I used the amount of solar penetration compared to winter peak loads for the x-axis to provide an indication of the relative amount of solar generation on each system. For DESC's values I used the amount of solar in 2025, as that is near the midpoint of their analysis.

Figure 2: Renewable Integration Costs Proposed in South Carolina

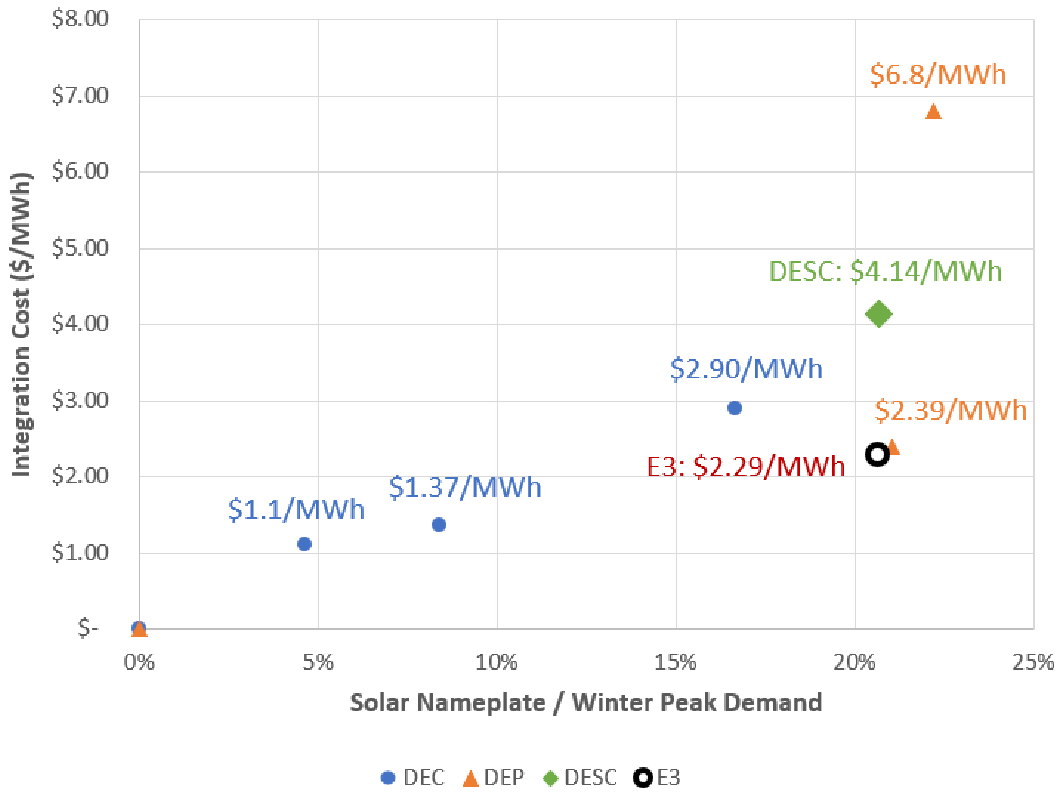


Figure 2 shows that my adjusted integration cost is very close to the value for DEP, and below the highest value for DEC. I believe the DEP result, however, is far more applicable to DESC than DEC. DEC has a higher percentage of coal and nuclear generation and lower percentage of natural gas generation than DESC and DEP. This would result in less flexibility for DEC and higher integration costs, all other things being equal.

Q. WHY IS IT REASONABLE TO COMPARE DESC TO DEC AND DEP?

A. The comparison to the DEC and DEP systems is useful because they are neighboring utilities subject to similar weather patterns. In addition, both DEC and DEP have seen significant, yet different solar penetration, which provides a useful comparison of estimated integration costs as a function of relative penetration levels.

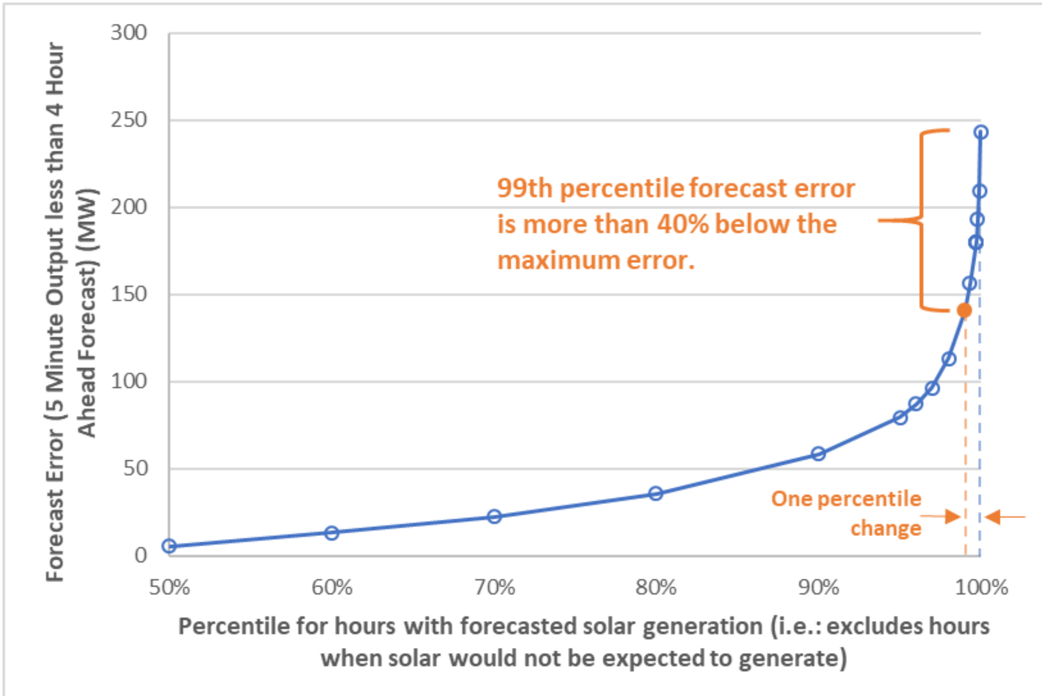
Q. HAVE YOU PERFORMED ADDITIONAL ANALYSIS TO EVALUATE THE REASONABLENESS OF YOUR RECOMMENDED 36.2% REDUCTION IN DESC'S PROPOSED INTEGRATION COST?

A. Yes. My recommendation is to include operating reserves based on 36.2% less solar forecast error than modeled in the DESC Integration Study. To assess the reasonableness of using this lower forecast error level, I reviewed the distribution of solar forecast error to determine the percentage of time that forecast error could exceed my recommended level.

Using the same NREL dataset as in the Integration Study, I compared the four (4) hour-ahead forecasts to the 5-minute actual production data for four (4) solar plants located in South Carolina near Beaufort, Charleston, Columbia, and Aiken. The distribution of forecast error is shown below in Figure 3 and displays a dramatic upswing at the right, indicating there are a few hours where the 5-minute solar output is far below the forecasted level. So few hours, in fact, that the 99th percentile forecast error is 40% below the maximum forecast error. As my recommended reduction to is only 36.2%, this suggests there is a less than 1% chance that solar forecast error would exceed my recommended level.

Given that this less than 1% of hours would only be problematic for DESC if there were also the simultaneous problems of lower than expected output from other scheduled generators, limited import ability, and higher than expected customer demand, I believe this is a reasonable balance of risk and costs, especially given my other concern that the DESC Integration Study contains a bias that increases costs.

Figure 3: Comparison of Maximum and 99th Percentile Solar Forecast Error



Q. DO YOU HAVE ADDITIONAL CONCERNS WITH THE ANALYSIS OF OPERATING RESERVES?

A. Based on the modeling description in the Integration Study, I believe reserve needs are overstated across the year by holding reserve levels constant throughout each day of the year.

Q. WHY DO YOU BELIEVE THE INTEGRATION STUDY REFLECTS RESERVES CONSTANT THROUGHOUT EACH DAY OF THE YEAR, AND HOW DOES THIS INFLUENCE THE RESULTS?

A. Within the Integration Study, there is an acknowledgement that "it is important to consider that many individual days within each case have lower forecasted solar than the maximum and hence need fewer reserves" (p. 26). Then the PROMOD was run "with each of [three] levels of reserves and then the results were blended using the weighted average of costs tied to the number of **days** that each level of reserves was required" (p. 27) [emphasis added]. Note that there is no mention of matching reserve requirements to hourly needs, but only matching based on the day.

Matching to the day is preferable in assuming the same reserve margin requirement of the entire year, but it is still vastly overestimating the amount of reserves that would need to be carried by DESC. It begs the question - why would the higher reserve levels for solar risk need to be carried in the evening or early morning when there is no solar output? It could be that there is no impact on costs from carrying the unneeded reserves for most hours; however, if there is an impact on costs for carrying unneeded reserves for some hours of the day, then the Company's integration costs would be excessively high.

Q. DO YOU HAVE OTHER RECOMMENDATIONS REGARDING THE COMPANY'S ANALYSIS REGARDING FUTURE VARIABLE INTEGRATION CHARGE UPDATES TO ITS STANDARD OFFER?

A. Yes. I recommend that DESC be required to update their analysis for future changes to their Standard Offer. As part of the update, DESC should be required to conduct technical workshops to gain input from the solar community and other stakeholders. Areas of agreement and disagreement should also be documented in a formal stakeholder process report to be submitted to the Commission along with the integration study.

Q. WHY DO YOU BELIEVE IT IS IMPORTANT TO HAVE STAKEHOLDER INVOLVEMENT IN THE UPDATING OF VARIABLE INTEGRATION CHARGES?

A. There are three (3) primary reasons that stakeholder engagement is important for this issue:

1) As research on renewable integration evolves and improves, stakeholders may be able to suggest advances and improvements to the Company's analysis;
2) Renewable integration charges are a new category of avoided costs, without the same rich history of estimation methods and approaches as the other cost categories. The stakeholder process would promote a more efficient interchange of ideas than may be realized through the testimony and hearing process; and
3) Renewable integration costs are intended to be charged primarily to the solar community, and as such the solar community should have a voice in the determination of the charges. For example, allowing more utility control of solar plant "dispatch" to allow for lower integration services charges could be economically superior to the assumption that solar could only be curtailed due to minimum generation limits. Such options might not be analyzed without the solar community's input.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION FOR DESC'S PROPOSED VARIABLE INTEGRATION CHARGE.

A. I recommend the Commission approve my calculated value of $2.29/MWh as the VIC.

<u>II. Avoided Energy Analysis, Discussion, and Recommendations</u>

Q. DESCRIBE THE METHODOLOGY THE COMPANY USED TO CALCULATE PROPOSED AVOIDED ENERGY COSTS.

A. As described by Company witness Neely in his direct testimony (p. 7), DESC calculates avoided energy costs using a methodology known as the Differential Revenue Requirement ("DRR"). The DRR method calculates the revenue requirements associated with two (2) different resource plan scenarios: a base case without a QF, and a change case with a QF.

For the long-run avoided energy cost calculations, in both the base case and the change case, DESC uses PROSYM, a production cost model, to simulate the commitment of generating units to serve load on an hourly basis over a 15-year Integrated Resource Plan ("IRP") planning horizon. The base case is constructed by using load forecasts and supply side resources as described in the IRP. The change case modifies the base case load forecasts and supply side resources by modeling the addition of 100 MW of solar generation to measure the reduction in energy costs equal to the impact of adding 100 MW of solar to DESC's supply side resources. For non-solar QFs, the change case modifies the base case by modeling the addition of a 100 MW block of generation available around the clock. Finally, the avoided energy costs are levelized and adjusted for taxes and working capital.

Q. IS THE DRR METHOD USED BY THE COMPANY TO CALCULATE AVOIDED ENERGY COSTS CONSISTENT WITH PURPA AND WITH THE METHODOLOGY PREVIOUSLY APPROVED BY THE COMMISSION?

A. Yes. This is one of the generally accepted methods for calculating PURPA avoided energy costs and is used throughout the United States. It is the same methodology used by DESC in Docket No. 2018-2-E and approved by the Commission in Order No. 2018-322(A), and it is reasonable to use a solar profile for solar specific QFs. However, I do not agree with the inputs and assumptions that DESC employed in developing their avoided energy cost estimates. My concerns and recommended corrections are addressed in detail later in my testimony.

Q. DESCRIBE THE UPDATES MADE BY THE COMPANY TO THE AVOIDED ENERGY COSTS AS PROPOSED IN THIS DOCKET COMPARED TO THOSE PREVIOUSLY APPROVED BY THE COMMISSION.

A. My review of the Company's current testimony, testimony filed in Docket No. 2018-2-E and work papers, indicates large changes in avoided energy costs are due to the decrease in fuel price between Docket No. 2018-2-E and the current docket. There appear to be no major changes in network configurations or import/export assumptions. Other variables include slight differences between the IRPs filed by DESC for 2018 and 2019, including differences in near-term purchased power amounts and a slight change in long-term annual sales growth (from 1.1% territorial sales growth annually to 0.9%). The 2019 IRP reflects some differences in the mix of generation resources, such as including more utility scale solar, but the scale of these differences is not likely to cause significant changes to which generation resources are on the margin in the PROSYM model. Thus, changes in load and components of electric supply are relatively slight and the difference in avoided energy costs for non-solar resources are primarily driven by the difference in fuel forecasts.

For solar resources that do not have a separate Company proposed VIC, DESC modeled the solar case using a paradigm where the utility required 35% more operating reserves than in the base case. This results in additional operating costs for the solar case and reduces the estimate of avoided costs from solar.

Q. ARE THE UPDATES TO THE AVOIDED ENERGY COSTS A REASONABLE AND CONSISTENT RESULT OF THE METHODOLOGY USED BY THE COMPANY?

A. Yes. DESC applied the approved DRR methodology to calculate avoided energy costs in a manner consistent with past filings of avoided energy rates. I have reviewed the fuel price forecasts DESC used in calculating the avoided energy cost for both the 2018 and 2019 fuel adjustment proceedings, and the forecast methodologies and values are consistent with the market. Given the minor changes in loads and supply, it is reasonable that the avoided energy cost calculation is driven primarily by changes in fuel price forecasts.

Q. DO YOU RECOMMEND THE COMMISSION APPROVE DESC'S ESTIMATE OF AVOIDED ENERGY COSTS FOR SOLAR RESOURCES?

A. No, I do not. DESC overstated the need for additional operating reserves to accommodate the integration of solar resources. The additional operating reserves reduce the net avoided energy costs estimated for solar resources. Therefore, an overestimation of the need for additional operating reserves incorrectly changes the avoided energy cost rates for solar resources.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE COMPANY'S PROPOSED AVOIDED ENERGY COSTS.

A. I identify three main concerns with the Company's calculation of proposed avoided energy costs:

1) The Company overstated the amount of operating reserves required for the incremental 100 MW of solar in the change case;
2) The Company's modeling requires operating reserves to provide solar integration services instead of potentially lower cost types of reserves; and
3) The Company's use of flawed assumptions that yield inconsistent results.

Q. PLEASE EXPLAIN HOW DESC OVERSTATED THE NEED FOR ADDITIONAL OPERATING RESERVES TO ACCOMMODATE THE INTEGRATION OF SOLAR RESOURCES.

A. As described in the direct testimony of Company witness Neely (p. 10), DESC modeled the avoided energy cost calculations with additional operating reserves equal to 35% of the installed solar capacity on DESC's electrical system, during solar generating hours. DESC derived the 35% value from 2018 solar data by looking at the observed drops in solar output over a one 1-hour period. The 35% value would be sufficient to cover 96% of the 1-hour drops in solar output.[1]

If solar output was analyzed over a shorter period of time, however, then the amount of the solar drops would be far less, and the need for additional reserves would be less. DESC provided ORS data in response to discovery that indicates solar drops over a 15-minute period only require additional reserves between 13% and 18% for the 96% certainty of being able to cover solar drops.[2] This lower amount of additional operating reserves would be more appropriate than the 35% value used by DESC because the 15-minute drops are more consistent with the types of generation changes that operating reserves are meant to address.

Operating reserves can have different definitions, but generally refers to having resources on-line and synchronized with the grid so that they can be fully generating power within ten (10) minutes. Other lower cost resources, such as non-spinning or supplemental reserves (generators that are not currently connected to the system but can be brought

[1] DESC response to ORS Audit Information Request 2-6 ("AIR 2-6").
[2] AIR 2-6.

online after a short delay), can be used to meet ramping needs over longer timeframes such as an hour. By increasing operating reserves, through an expensive fast responding option, to address a slow 1-hour problem, DESC has overestimated the additional costs of solar integration.

Q. DO YOU BELIEVE THAT IT MAY BE APPROPRIATE FOR DESC TO USE SOLAR DROPS OVER AN EVEN SHORTER TIMEFRAME THAN 15 MINUTES?

A. Yes. 15-minute data was the shortest timeframe provided in DESC data response AIR 2-6. However, it may be appropriate to calculate the need for additional operating reserves based on 5-minute solar drops, instead of 15-minute solar drops. The DESC data indicates that the additional operating reserve requirement to meet a 96% certainty declines when the solar drop is calculated over small time increments, ranging from four (4) hours down to fifteen (15) minutes. Therefore, I expect that 5-minute data would result in an even lower solar drop level and less of an increase to operating reserves.

Q. WHAT OTHER FUNDAMENTAL FLAWS DID YOU FIND IN THE COMPANY'S CALCULATIONS?

A. Even if an appropriate operating reserve level change were identified, there appears to be fundamental flaws in the calculation method used by DESC. Data obtained by ORS from the Company provided the calculation of the annual increase in operating costs due to the higher solar operating reserve requirements.[3] The values are reproduced below in Table 6, and show the costs actually alternate between positive and negative values. In other words, some years reflect a higher cost, but other years reflect a lower cost. The

[3] DESC response to ORS Audit Information Request 2-7 ("AIR 2-7")

inconsistent results cause me to question the validity and accuracy of DESC's method and model for the impact of the operating reserve levels on operating costs.

Table 6: Costs for Additional Operating Reserves for Solar Integration (AIR 2-7)

Year	Additional Operating Reserve Costs ($/MWh)
2020	-1.40
2021	0.37
2022	-0.01
2023	-1.28
2024	0.06
2025	-0.08
2026	-1.97
2027	0.60
2028	1.62
2029	-0.23

Q. GIVEN THE FLAWS IN DESC'S ANALYSIS, WHAT DO YOU RECOMMEND FOR AVOIDED ENERGY CREDITS FOR SOLAR QFS WITHOUT A VIC?

A. I recommend that avoided energy costs should not be adjusted for additional operating costs for solar projects. Instead, avoided energy costs should be estimated similar to Docket No. 2018-2-E, based on the normal operating reserve level (no additional operating reserve requirement) for both the base case and the solar change case.

The recommended values can be estimated by either re-running the DESC production simulation models using the normal operating reserve levels, or by adjusting the DESC proposed values by removing the effect of the higher operating reserve levels for the solar change case. For my testimony, I use the latter approach.

Because additional operating reserves should increase operating costs, I interpret the values in Table 6 to be the change in avoided cost credits due to the increased solar operating reserves. I therefore subtracted the Table 6 values from the DESC proposed avoided cost credits in order to reverse the effect of the higher operating costs. I also adjusted the recommended avoided cost credits for the associated line losses, working capital impacts, gross receipts taxes, and generation taxes

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR DESC'S PROPOSED AVOIDED ENERGY CALCULATIONS.

A. I recommend the Commission:

1) Reject DECS's proposed avoided energy costs for solar projects that are not assessed a VIC;
2) Reject DESC's proposed avoided energy costs for solar projects that are assessed a VIC;
3) Require the Company to separately state the avoided energy credits from the VIC charge in the Rate PR-1and Standard Offer tariffs; and
4) Approve my proposed avoided energy calculations.

My recommended Rate PR-1 and Standard Offer avoided energy rates for solar QFs compared to those proposed by the Company are shown below in Tables 7 and 8:

Table 7: Rate PR-1 Avoided Energy Rates for Solar QFs ($/kWh)

Time Period	DESC Proposed ($/kWh)	E3 Proposed ($/kWh)
May 2019-April 2020	.03149	.03299

Table 8: Rate PR-Standard Offer Avoided Energy Rates for Solar QFs ($/kWh)

Time Period	DESC Proposed ($/kWh)	E3 Proposed ($/kWh)
2020-2024	.02126	.02174
2025-2029	.02450	.02457

III. Avoided Capacity Analysis, Discussion, and Recommendations

Q. DESCRIBE THE METHODOLOGY THE COMPANY USED TO CALCULATE PROPOSED AVOIDED CAPACITY COSTS.

A. DESC also calculated the avoided cost of capacity using the DRR method. The capacity cost calculation starts with the difference in fixed costs for a base resource plan compared to a resource plan with an additional 100 MW of generation capacity. The additional 100 MW of generation allows for the deferral of planned new generation resources and the associated cost savings are then divided by 100 MW and levelized to calculate the avoided capacity cost.

Q. IS THE METHODOLOGY USED BY THE COMPANY TO CALCULATE AVOIDED CAPACITY COSTS CONSISTENT WITH PURPA AND THE METHODOLOGY PREVIOSLY APPROVED BY THE COMMISSION?

A. Yes. The DRR methodology is one of the generally accepted methods for calculating PURPA avoided capacity costs and is used throughout the United States. It is the same methodology used by DESC in Docket No. 2018-2-E and approved by the Commission in Order No. 2018-322(A).

Q. DO YOU AGREE WITH THE INPUTS AND ASSUMPTIONS DESC USED TO DEVELOP THE AVOIDED CAPACITY COST ESTIMATES?

A. No. I disagree with inputs and assumptions that DESC employed in developing their avoided capacity cost estimates. My concerns and corrections are discussed in detail later in my testimony.

Q. WHAT DOES DESC PROPOSE FOR AVOIDED CAPACITY COSTS?

A. DESC has proposed a value of zero (0) for the avoided capacity costs for incremental solar projects for Rates PR-1, the Standard Offer and in the Value of DER. For non-solar projects the Company proposes an avoided capacity cost rate of $.07346/kWh for both the proposed Rate PR-1 and Standard Offer.

Q. DO YOU AGREE WITH THE COMPANY'S AVOIDED CAPACITY VALUE FOR NON-SOLAR PROJECTS?

A. No. As discussed later in my testimony, the Company made several assumption errors that lead to an underestimation of avoided capacity value for DESC. Specifically, the Company used the wrong target reserve margin in determining capacity need, assumed the use of low cost purchased power when a CT should be added, assumed an overly long CT lifetime, and used a capacity change assumption that is mismatched to the assumed CT capacity size.

Q. DO YOU AGREE WITH THE COMPANY'S AVOIDED CAPACITY VALUE OF ZERO (0) FOR SOLAR PROJECTS?

A. No. The assumptions used by the Company to calculate avoided capacity for solar projects are overly simplistic and deterministic. I propose an approach that results in a reasonable value for avoided capacity for solar resources.

Q. PLEASE SUMMARIZE YOUR CONCERNS ABOUT THE COMPANY'S PROPOSED AVOIDED CAPACITY COSTS FOR SOLAR PROJECTS.

A. The Company understated the avoided capacity cost estimates due to the use of unrealistic assumptions:

1) The Company incorrectly concludes incremental solar provides no capacity value in the winter;

2) The Company does not apply the results of the reasonable probabilistic calculation to the avoided capacity calculation; and

3) The Company's calculations for cost of avoidable capacity are based on the costs for purchased power instead of using the costs for a combustion turbine ("CT") as reflected in the Company's most recent IRP.

Q. WHAT IS THE BASIS FOR DESC'S CONCLUSION THAT INCREMENTAL SOLAR PROVIDES NO CAPACITY VALUE IN THE WINTER SEASON?

A. Company witness Lynch testifies that "DESC needs capacity in the winter and solar does not provide capacity on early winter mornings before sunrise when the system peaks nor during peak hours on most non-summer days when the system peaks before sunrise or after sunset" (Lynch, p. 11).

Q. WHAT ARE DESC'S STATED REASONS FOR ASSIGNING A ZERO (0) VALUE TO THE AVOIDED CAPACITY COSTS FOR SOLAR?

A. DESC asserts the "need for capacity is driven by the winter season" and "because solar does not consistently provide capacity during the winter peak periods, the Company is unable to avoid any of its projected future capacity needs and, therefore, the avoided capacity cost of solar is zero" (Neely, p. 13).

Q. DO YOU AGREE THAT CAPACITY NEED IS DRIVEN SOLELY BY PEAK DEMAND?

A. No. The need for capacity is not a simple matter of summer versus winter capacity need, but rather the comprehensive capacity needs over the whole year. The DESC approach of only analyzing the summer or winter seasonal peak is a simplistic way of evaluating the need for and value of capacity resources. DESC's approach is flawed due to the methods excessive focus on the demand part of system planning (when the peak occurs) and insufficient recognition of the risk from generator unit outages. By ignoring the full range of generator outage risk, DESC fails to recognize the outage risks that exist over the non-winter months.

Q. DID THE COMPANY PROVIDE ANY CALCULATION THAT DEMONSTRATES A POTENTIAL CAPACITY VALUE FOR SOLAR RESOURCES OTHER THAN ZERO?

A. Yes. Due to feedback from other parties in previous avoided cost proceedings, Company witness Lynch performed a probabilistic analysis using the Effective Load Carrying Capacity ("ELCC") method which demonstrates solar provides capacity value equal to 24% of nameplate capacity (Lynch, p. 10).

ELCC is the capacity contribution of a resource, divided by the nameplate capacity of the resource. For solar, DESC calculated an ELCC of 11.8% for the 501st MW of solar on the DESC system through the 1,000th MW of solar on the DESC system. Therefore, each kW of new solar up to 1,000 MW of solar would be reducing DESC's capacity needs by 0.118 kW.

Using the Company's own calculation, solar resources should receive a credit equal to 24% of their nameplate capacity. Providing a credit less than calculated for a rate specific to solar generators would be unfair to these small power producers and violate the non-discriminatory guideline of Section 58-41-20(A) of Act 62.

Q. WHY IS IT APPROPRIATE TO RELY ON A PROBABLISTIC ANALYSIS LIKE ELCC TO DETERMINE THE CAPACITY CONTRIBUTION OF INTERMITTENT RESOURCES SUCH AS SOLAR?

A. ELCC analyses were developed in the electric industry specifically for the purpose of determining capacity contributions from intermittent resources. As an example, see the NREL report, *Using wind and solar to reliably meet electricity demand*, **https://www.nrel.gov/docs/fy15osti/63038.pdf.**

E3 is at the forefront of evaluating the impact of renewable resources on utility planning and operations. Through our work it is abundantly clear that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given time period, not just a single peak hour. Moreover, the importance of probabilistic models is generally recognized across the industry, as noted by the North American Electric Reliability Corporation's ("NERC") *Probabilistic Adequacy and Measures Technical Reference Report (April 2018):*

> There is a recognized need to support probability-based resource adequacy assessment resulting from the changing resource mix with significant increases in variable and energy-limited resources (intermittent in nature), changes in net demand profiles resulting in the shifting of the hour of the peak demand, and other factors can have an effect on resource adequacy. (NERC, p.6)

Q. IF THE COMPANY INSISTS ON USING THEIR CURRENT METHOD FOCUSED ON WINTER PEAK AND THE ADDITION OF 500 MW OF SOLAR TO CALCULATE SOLAR CAPACITY, WHAT SOLUTION WOULD YOU RECOMMEND FOR CALCULATING A MORE REASONABLE VALUE?

A. The solution is to amend the planning process to recognize the contribution of solar resources toward DESC's capacity needs. For the existing 598 MW of capacity interconnected to the DESC system as of July 31, 2019 (Raftery, p. 14), 37% of nameplate capacity (Lynch, p. 10) should be counted toward DESC's capacity needs. For the next tranche of solar, such as the solar that would be implemented using Rates PR-1 and PR-

Standard Offer from this docket, 11.8% of nameplate capacity should be recognized. The 11.8% is based on the ELCC provided by the increase in solar on the DESC system from 500 MW to 1,000 MW (Lynch, Table 3b, 59 MW of ELCC divided by 500 MW of incremental solar). This lower ELCC percentage for future solar recognizes the declining capacity benefits of solar at higher penetration levels.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO CALCULATE A MORE REASONABLE ESTIMATE OF SOLAR CAPACITY.

A. To calculate a more reasonable solar capacity value, I apply the DESC DRR model and Solar plus Storage workpaper spreadsheet [4] and update the following inputs:

1) Corrected the Company's error for winter target reserve margin from 14% to 21%;
2) Corrected the Company's error and model the addition of a CT (instead of purchased power) when capacity needs approach the 93 MW size of a CT in the year;
3) Corrected the economic lifetime of a CT from sixty (60) years to twenty (20) years;
4) Included a 93 MW change in capacity between the base case and change case, instead of 100 MW, to be consistent with the size of the CT additions modeled by DESC; and
5) Included the ELCC solar capacity factor of 11.8% instead of assuming a zero (0) capacity value for solar.

[4] AIR 2-4, Avoided_Capacity_-_10_year_ICT_-_081319_.xlsx, Solar_and_Battery_081319_.xlsx

To calculate a more reasonable solar capacity value, I start with the full DESC avoided capacity cost, multiplied by the ELCC of 11.8%. This is the avoided capacity cost for solar resources, expressed in dollars per kW. I then divide the solar avoided capacity cost by 2,076 kWh per kW to derive the solar capacity credit in dollars per kWh. 2,076 is the solar output level for a one (1) kW plant with an annual capacity factor of 23.8%.

Q. WHY DO YOU USE A 20-YEAR ECONOMIC LIFE FOR A CT PLANT INSTEAD OF DESC'S 60-YEAR ECONOMIC LIFE?

A. It is common industry practice to calculate the annual value of generation capacity as the direct cost of the CT multiplied by a Fixed Charge Rate. The Fixed Charge Rate is the percentage of total plant cost that is required each year over the economic life of the plant to recover its full capital-related revenue requirement. DESC follows this approach but uses a 60-year economic life for the CT, rather than a 20-year economic life for the CT that is used by both PJM and AESO for their Cost of New Entry reports, by the highly regarded Lazards Levelized Cost of Energy Analysis report[5] and by jurisdictions like California for their avoided capacity costs. By using an overly long economic life in the Fixed Charge Rate calculation, DESC is spreading the capital-related costs of the CT over an excessive number of years and artificially lowering the estimate of costs that would need to be collected in each year

[5] California avoided capacity cost:ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/ACC_2019_v1b.xlsb

PJM Cost of New Entry report: https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx

Lazard Levelized Cost of Energy Analysis: https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

AESO Cost of New Entry: https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf for the CT owner. Correcting the CT life to DESC's avoided cost spreadsheet tool increases the CT Fixed Charge Rate from 13.36%/ per year to 15.24% per year. This increases the avoided capacity cost by 14%.

Q. DESC DEVELOPED THE DRR AVOIDED CAPACITY CALCULATION USING A 100 MW CHANGE IN GENERATION BETWEEN THE BASE CASE AND THE CHANGE CASE. WHY DO YOU USE A 93 MW CHANGE?

A. I use a 93 MW change in capacity between the base case and the change case because 93 MW is the capacity of the CT units that DESC adds for new capacity. Because of the lumpiness (limited flexibility of sizing) of CT plants, a 100 MW or a 93 MW change result in the same Change Case expansion plan. However, since the cost difference between the Change Case and the Base Case expansion plans are divided by the capacity change (100 MW or 93 MW), the choice of capacity change amounts will affect the final dollar per kW avoided capacity cost. Using the 100 MW change results in an avoided cost that is 7% lower than the avoided cost using the 93 MW change.

Because of the lumpiness of the size of CT additions, avoided capacity costs can easily be manipulated up or down through mismatches in capacity changes and CT sizes. For example, I can increase the avoided capacity factor by almost a factor of 18 (from \$0.24725/kWh to \$4.3925/kWh) by using a 15 MW capacity change with a 93 MW CT plant size.

To avoid such manipulations, the DRR method should match the capacity change for the Change Case with the size of the CT additions, hence my use of the 93 MW for both. Alternately, one could use a CT plant with 100 MW capacity with a 100 MW change case, but in either case the change case capacity reduction should be the same as the size of the CT plant.

Q. WHAT CHANGES HAVE THE MOST IMPACT ON THE CALCULATION OF AVOIDED CAPACITY COSTS?

A. The correction of the winter reserve margin and the consistent use of CTs to meet capacity needs has the largest impact. I also detected an error in the DESC model. The Company incorrectly used a 14% reserve margin in their model, which reduces the need for capacity, thereby reducing the value of QF capacity. A 21% reserve margin is DESC's stated reserve margin for evaluating the need for peak capacity (Lynch, p. 17), and also the reserve margin used for their resource planning, as shown on their Load and Resource Balance tables on pages 47-48 of their 2019 IRP.

In addition, DESC assumed that additional capacity would be purchased from the market at low prices and incorporated this assumption into the base case. This biased assumption reduces the avoided capacity value because it assumes a low-cost capacity resource instead of the standard CT unit. Power purchases could be valid for small amounts of capacity need; however, DESC assumed market purchases when the capacity need was as much as 277 MW, which is far above the 93 MW size of a CT unit. Indeed, there are four (4) years in DESC's base plan that contain more than 93 MW of market capacity purchases.

To introduce further bias into the Company's model, the Company does not use any low-cost market purchases in the change case. DESC has not provided any justification to ORS for treating capacity needs differently in the two cases. The avoided cost analysis should only change the available generation capacity in the change case in order to calculate the impact of changes in capacity. What DESC has done is change both the generation capacity **and** the method the Company uses to meet generation capacity needs (i.e.: the use of market purchases in only the base case). Moreover, DESC provided no justification for this change in generation capacity procurement strategies between the base case and the change case. Therefore, I conclude that the Company has not supported its assumptions for using power purchases in the base case when capacity needs near 93 MW.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE AVOIDED CAPACITY RATES FOR RATE PR-1, RATE PR-STANDARD OFFER, AND THE VALUE OF DER FOR SOLAR QFS.

A. I recommend capacity values that are substantially higher than those proposed by DESC using the assumptions and calculations as described above. A summary of my recommendations compared to DESC's proposed rates are shown below in Table 9.

Table 9: Avoided Capacity Rate Recommendations

Rate	**DESC Proposed**	**E3 Recommended**
Standard Offer Non-Solar QFs. *Dec through Feb, 6 am to 9 am*	$73.46/MWh	$247.25/MWh
Standard Offer Solar QFs *All hours*	$0.00	$3.79/MWh
Solar with Storage	$3.17/kW per year	$7.08/kW per year
Rate PR-1 *Dec through Feb, 6 am to 9 am*	$0.07346/kWh	$0.24725/kWh

IV. Value of DER Analysis, Discussion, and Recommendations

Q. DESCRIBE THE CHANGES TO DESC'S PROPOSED TOTAL VALUE OF DER.

A. As required by Commission Order No. 2015-194, DESC must calculate eleven (11) components of value for DER. In Docket No. 2018-2-E, DESC calculated these eleven (11) components of value, and in Order No. 2018-322(A), the Commission determined the values DESC calculated complied with the Methodology. On page 22 of Company witness Lynch's direct testimony, DESC reports the updated values for these same eleven (11) components.

Q. DO YOU FIND THE REASONS OFFERED BY THE COMPANY FOR WHY IT HAS ZERO (0) VALUE FOR FIVE (5) OF THE OTHER COMPONENTS OF THE VALUE OF DER REASONABLE?

A. Yes. DESC followed the methodology approved by the Commission in Order No. 2015-194 to evaluate the value of each component of the value of DER. Regarding Transmission and Distribution ("T&D") Capacity, some jurisdictions recognize the value that DER resources provide in deferred T&D investments and therefore attribute capacity value to resources like solar. DESC's practice of designing T&D circuits to assume DER is not generating due to weather factors or because DER resources are off line is a conservative approach. In respect to avoided carbon dioxide ("CO_2") emissions, some jurisdictions recognize value in avoided CO_2 emissions and the Commission directs DESC to use zero (0) monetary value for CO_2 emissions "until state or federal laws or regulations result in an avoidable cost on Utility systems for these emissions." (Order No. 2015-194, p. 9).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE AVOIDED CAPACITY AND UTILITY INTEGRATION AND INTERCONNECTION COSTS COMPONENTS.

A. Based on my analysis and resulting calculations, I recommend updating the components for Avoided Capacity Costs and Utility Integration and Interconnection Costs. Tables 10 and 11 below summarize the values approved in Order 2018-322(A) in Docket No. 2018-2-E, the proposed values as filed by DESC in this docket, and my recommended values based on my analysis as previously discussed in my testimony. Note that for the current period, I included zero (0) capacity value in my recommendation because DESC indicated no need for additional capacity in their 2019 IRP until the year 2022.

Table 10: 10-Yr Levelized Value of DER ($/kWh): 2019 Proposed (Neely pp. 22) and E3 Recommended

	DESC 2019 IRP Planning Horizon (10-yr Levelized)	E3 Recommended (10-yr Levelized)	Components
1	$0.02210	**$0.02239**	Avoided Energy Costs
2	$0.00000	**$0.00379**	Avoided Capacity Costs
3	$0.00000	$0.00000	Ancillary Services
4	$0.00000	$0.00000	T&D Capacity
5	$0.00003	$0.00003	Avoided Criteria Pollutants
6	$0.00000	$0.00000	Avoided CO_2 Emission Cost
7	$0.00000	$0.00000	Fuel Hedge
8	$0.00000	$0.00000	Utility Integration & Interconnection Costs

9	$0.00000	$0.00000	Utility Administration Costs
10	$0.00116	$0.00116	Environmental Costs
11	$0.02329	$0.027370	Subtotal
12	$0.00190	$0.002018	Line Losses @ 0.9245
13	**$0.02519**	**$0.029388**	**Total Value of DER**

1 *Table11: Current Period Value of DER ($/kWh): 2019 Proposed (Neely pp. 22) and E3*
2 *Recommended*

	DESC 2019 Current Period	E3 Recommended Current Period	Components
1	$0.03053	**$0.03299**	Avoided Energy Costs
2	$0.00000	$0.00000	Avoided Capacity Costs
3	$0.00000	$0.00000	Ancillary Services
4	$0.00000	$0.00000	T&D Capacity
5	$0.00003	$0.00003	Avoided Criteria Pollutants
6	$0.00000	$0.00000	Avoided CO_2 Emission Cost
7	$0.00000	$0.00000	Fuel Hedge
8	$0.00000	$0.00000	Utility Integration & Interconnection Costs
9	$0.00000	$0.00000	Utility Administration Costs
10	$0.00093	$0.00093	Environmental Costs
11	$0.03149	$0.03395	Subtotal
12	$0.00257	$0.00256	Line Losses @ 0.9245
13	**$0.03406**	**$0.03651**	**Total Value of DER**

V. Form Contract PPAs and Notice of Commitment to Sell Forms Recommendations

Q. DO THE COMPANY'S PROPOSED FORMS GENERALLY COMPLY WITH PURPA AND FERC IMPLEMENTATION GUIDELINES?

A. In general, the Company's proposed forms comply with PURPA; however, there are some sections that require correction and/or clarification.

Q. BASED ON YOUR EXPERIENCE, IS THE COMPANY'S PROPOSED NOTICE OF COMMITMENT TO SELL FORM CONSISTENT WITH PURPA AND FERC IMPLEMENTATION GUIDELINES?

A. Yes. The commitment to sell form functions to establish a non-contractual legally enforceable obligation ("LEO") option for a QF which contractually obligates the QF to sell and deliver its full output to the utility and the utility to purchase the delivered energy and capacity at the utility's avoided cost rates over the specified term length. PURPA and FERC have given latitude to states in determining the required standards for forming a LEO. FERC mandates that a LEO cannot depend on the willingness of the purchasing utility to execute a contract with the QF. Act 62 requires that utilities create a notice of commitment to sell form which a QF can unilaterally execute which forms a LEO obligation between the utility and the QF. It is my understanding that the notice of commitment to sell form, proposed by the Company in accordance with the requirement in Act 62, is consistent with PURPA and FERC. Furthermore, the requirements contained in the notice of commitment to sell form (such as demonstrating site control, establishing a delivery date and delivery term, and requirement to submit an interconnection request to the utility) are consistent with PURPA and FERC implementation guidelines, which have given state regulatory authorities latitude in determining appropriate requirement standards.

Q. PLEASE EXPLAIN YOUR RECOMMENDATIONS TO PROVIDE FURTHER CLARIFICATIONS TO CLAUSE 8(iii) OF THE COMMITMENT TO SELL FORM.

A. In my opinion there is a lack of clarity in clause 8(iii), which I reproduce below. Section 8 governs circumstances in which the Notice of Commitment shall automatically terminate, and clause 8(iii) reads as follows:

> If the seller does not commence delivery of its electrical output to the Company within 365 days of the Submittal Date; provided, however, the Company has sufficient interconnection facilities are not available, the Company shall inform the Seller at least 30 calendar days prior to the expiration of such 365-day period, and shall give the Seller a description of the additional facilities required to establish adequate interconnection facilities. (Folsom, Exhibit No._(JEF-3), p. 3)

As I understand the testimony of Company witness Folsom, this clause is meant to ensure that “the QF will not be penalized as a result of inadequate interconnection facilities” (Folsom p. 26). Section 8(iii) ensures that the QF will not have an automatic cancelation of its Notice of Commitment to Sell if any such interconnection facilities are not available. However, it is unclear which entity (the QF or DESC) is responsible for installing additional facilities to establish adequate interconnection facilities, and whether the QF is eligible for any payments or damages due to delays. I recommend the Company clarify the entity responsible for installing additional facilities and clarify if, and the amount of, liquidated damages or other payments will be made by the Company to the QF.

Q. ACT 62 REQUIRES THAT THE COMMISSION APPROVE PPAS WITH "COMMERCIALLY REASONABLE" TERMS. CAN YOU DEFINE COMMMERCIALLY REASONABLE?

A. While I am not an attorney, I have some experience with contract terms. It is my understanding that the term "commercially reasonable" is used frequently in contracts, but neither FERC nor the South Carolina Legislature defined "commercially reasonable" in the context of Standard Offer contracts. As applied to contract terms as a whole (such as a PPA) that encompasses risk allocation and assignment of rights, responsibilities, and obligations, I would offer "commercially reasonable" to mean terms which would be acceptable to two independent parties entering into a contract for their mutual benefit under their own free will.

Q. DOES THE COMPANY'S PROPOSED STANDARD OFFER PPA FOR QFS CONFORM TO INDUSTRY STANDARDS?

A. In my opinion, the standard offer PPA terms and conditions are generally commercially reasonable and conform to industry standards. However, I have a concern with the lack of clarity in section 6.1(a), reproduced below.

> a) No later than sixty (60) calendar days prior to the projected Commercial Operation Date, and prior to October 1 of each Calendar Year thereafter during the Term, and without waiving any rights of Buyer or the requirements and obligations of Seller specified in Section 3.5, Seller shall submit to Buyer in writing a good faith estimate of each month's average-day energy production to be generated by the Facility and delivered to Buyer during the following Calendar Year, including the time, duration and magnitude of any scheduled maintenance period(s) or reductions in Net Energy to be delivered to Buyer. This forecast shall include an expected range of uncertainty based on historical operating experience. Seller shall update the forecast for each month at least five (5) Business Days before the first Business Day of such month. In addition, Seller shall promptly update a forecast at any time information becomes available indicating a change in

> the forecast relative to the most previously provided forecast. (Folsom, Exhibit No._(JEF-2), p. 26)

Specifically, I am concerned about the language "expected range of uncertainty based on historical operating experience." It is unclear what constitutes an acceptable "expected range of uncertainty" or what QF with no historical operating experience would be requested to provide. I would recommend the Company clarify either a precise calculation method for an acceptable "expected range of uncertainty" or strike the unclear requirement from the Standard Offer PPA form.

Q. PLEASE EXPLAIN YOUR OTHER SUGGESTED RECOMMENDATIONS TO THE COMPANY'S TERMS AND CONDITIONS REFLECTED IN THE PROPOSED STANDARD OFFER PPA?

A. My understanding is in April 2019 SCANA was acquired by Dominion Energy, Inc. and South Carolina Electric & Gas Company changed its name to Dominion Energy South Carolina, Inc. In various places, the proposed PPA references SCANA. I recommend the Company be required to update these references to the appropriate new name. As an example, I list two references within the Standard Offer:

- Definition of "Surety Bond" references the "SCANA Corporate Credit Department" (Folsom Exhibit No._(JEF-2), p. 14); and
- Attachment D, Section 7 references "SCANA Corporation and its subsidiaries" (Folsom Exhibit No._(JEF-2), p. 63).

Q. DID THE COMPANY OFFER A TEN-YEAR STANDARD OFFER PPA TERM LENGTH WITH TERMS AND CONDITIONS CONSISTENT WITH PURPA AND FERC IMPLEMENTATION GUIDELINES?

A. Yes. FERC requires that QFs have the option of either providing energy with avoided costs calculated at time of delivery, or of providing energy and capacity with a LEO for delivery of energy or capacity for a fixed term length, with avoided cost rates specified either prior to the obligation incurred or based on avoided cost rates calculated at time of delivery. FERC gives state regulatory authorities broad latitude in setting avoided cost terms, including setting term lengths for fixed rate contracts. Act 62 requires utilities to include 10-year contract terms in the Standard Offer. The Company's Standard Offer includes a 10-year term option and associated rates are included in the proposed Rate PR-Standard Offer tariff.

Q. ARE THE PROPOSED STANDARD OFFER CURTAILMENT TERMS AND CONDITIONS CONSISTENT WITH PURPA AND FERC IMPLEMENTATION GUIDELINES?

A. Yes. FERC regulations allow for curtailment of QFs. In the proposed Standard Offer PPA Section 5.1(f) clarifies the Company will only curtail the QF for Emergency Conditions and events of Force Majeure, and Section 5.1(e) clarifies that the Company will not curtail for economic reasons. I believe the Company's proposed Standard Offer curtailment terms and conditions are consistent with PURPA and FERC implementation guidelines.

Q. DO THE STANDARD OFFER AND PPA PROHIBIT TERMINATION OF THE PPA OR COLLECTION OF DAMAGES AS A RESULT OF INTERCONNECTION DELAYS AS CONTEMPLATED IN SECTION 58-41-20(E)(3)(A) OF ACT 62?

A. As I understand, the Standard Offer includes a provision for a delay without damages due if a delay is due to a Force Majeure event. I do not find any language in the

Standard Offer which would indicate an allowance of termination of the PPA, or collection of damages from the QF, as a result of interconnection delays due to the electrical utility.

Q. DO THE STANDARD OFFER AND PPAS PROHIBIT THE COMPANIES FROM REDUCING THE PRICE PAID TO QFS BASED ON COSTS RESULTING FROM THE INTERMITTENT NATURE OF THE QF CONTEMPLATED IN SECTION 58-41-20(E)(3)(B) OF ACT 62?

A. While the Standard Offer and PPA do not contain a provision that allows for a variable integration charge, the PPA does include a price reduction based on the Company's integration costs for intermittent generation; this price reduction is addressed in the avoided cost methodology, as discussed previously in my testimony.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED FORMS.

A. I recommend the Commission:

1) Require the Company to clarify clause 8(iii) in the Commitment to Sell Form;
2) Require the Company to clarify section 6.1(a) of the Standard Offer PPA; and
3) Correct any references to SCANA in the forms to Dominion Energy South Carolina, Inc.

VI. Summary of Recommendations

Q. PLEASE PROVIDE A SUMMARY OF YOUR RECOMMENDATIONS.

A. ORS offers the following recommendations for the Commission's consideration:

1) Reject DESC's proposed avoided energy rates for solar projects that are not assessed in the VIC;

2) Reject DESC's proposed avoided energy rates for solar projects that are assessed a VIC;
3) Require the Company to separately state the avoided energy rates from the VIC in the Rate PR-1 and Standard Offer tariffs;
4) Approve my proposed avoided energy rate calculations;
5) Reject DESC's proposed VIC and approve my $2.29/MWh VIC;
6) Reject DESC's avoided capacity rates for both solar and non-solar QFs;
7) Approve my avoided capacity rates that reflect a fair and unbiased valuation consistent with industry standard assumptions; and
8) Require the Company clarify a calculation method to account for "expected uncertainty" of QF production forecasts in the Standard Offer PPA, clarify language regarding interconnection delays in the Notice of Commitment to Sell form, and request the Company revise the form PPA to update references to SCANA Corporation.

Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Company, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Brian Horii

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Energy Resources, and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario, Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, and South Carolina Office of Regulatory Staff.

Resource Planning:

- Authored the Locational Net Benefits Analysis (LNBA) tool used by California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island, demand response from large customers, and new clean power generation
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments
- Evaluated the sale value of hydroelectric assets in the Western U.S.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the “E3 Calculator” tool used as the basis for all energy efficiency programs evaluations in California since 2006
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities
- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions; also authored the model’s sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs

- Co-author of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005
- Principal consultant for the California Energy Commission's Title 24 building standards to reflect the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage
- Principal investigator for the 1992 EPRI report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities in the U.S., Canada, and the Middle East
- Principal author of the *Full Value Tariff and Retail Rate Choices* report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings since 2008
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions
- Consulted to the New York State Public Service Commission on appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and appropriate cost tests
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997); principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix)
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work has addressed marginal cost-based revenue allocation and rate design; estimating area and time specific marginal costs; incorporating customer outage costs into planning; and designing a comprehensive billing and information management system for a major energy services provider operating in California

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in California's Central Valley
- Developed the quantitative modeling of net benefits to the California grid of SDG&E's Sunrise Powerlink project in support of the CAISO's testimonies in that proceeding
- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation

- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades
- Developed the cost basis for BC Hydro's wholesale transmission tariffs
- Provided support for numerous utility regulatory filings, including testimony writing and other litigation services

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluating electricity sector greenhouse gas emissions and trade-offs
- Primary architect of long-term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept; projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models
- As PG&E's expert witness on revenue allocation and rate design before the California Public Utilities Commission (CPUC), was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC and extending their application to cost effectiveness analyses of DSM programs
- Created interactive negotiation analysis programs and forecasted electric rate trends for short-term planning

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped develop methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints; created a model for determining the least-cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs
- Co-authored *The Delta Report* for PG&E and EPRI, which examined the targeting of DSM measures to defer the expansion of local distribution facilities

Education

Stanford University Palo Alto, CA
M.S., Civil Engineering and Environmental Planning 1987

Stanford University — Palo Alto, CA
B.S., Civil Engineering — 1986

Citizenship

United States

Refereed Papers

1. *Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," The Energy Journal, 33:1, 207-229.*
2. *Orans, R., C.K. Woo, B. Horii, M. Chait and A. DeBenedictis (2010) "Electricity Pricing for Conservation and Load Shifting," Electricity Journal, 23:3, 7-14.*
3. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*
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10. *Heffner, G., C.K. Woo, B. Horii and D. Lloyd-Zannetti (1998) "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," IEEE Transactions on Power Systems, PE-493-PWRS-012-1997, 13:2, 560-567.*
11. *Chow, R.F., Horii, B., Orans, R. et. al. (1995), Local Integrated Resource Planning of a Large Load Supply System, Canadian Electrical Association.*
12. *Woo, C.K., R. Orans, B. Horii and P. Chow (1995) "Pareto-Superior Time-of-Use Rate Option for Industrial Firms," Economics Letters, 49, 267-272.*
13. *Pupp, R., C.K.Woo, R. Orans, B. Horii, and G. Heffner (1995), "Load Research and Integrated Local T&D Planning," Energy - The International Journal, 20:2, 89-94.*

14. *Woo, C.K., D. Lloyd-Zannetti, R. Orans, B. Horii and G. Heffner (1995) "Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation," The Energy Journal, 16:2, 111-130.*
15. *Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994), "Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," Energy - The International Journal, 19:12, 1213-1218.*
16. *Woo, C.K., B. Hobbs, Orans, R. Pupp and B. Horii (1994), "Emission Costs, Customer Bypass and Efficient Pricing of Electricity," Energy Journal, 15:3, 43-54.*
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3. *Horii, B., R. Orans, A. Olsen, S. Price and J Hirsch (2006) Report on 2006 Update to Avoided Costs and E3 Calculator, Prepared for the California Public Utilities Commission.*
4. *Horii, B., (2005) Joint Utility Report Summarizing Workshops on Avoided Costs Inputs and the E3 Calculator, Primary author of testimony filed before the California Public Utilities Commission.*
5. *Horii, B., R. Orans, and E. Cutter (2005) HELCO Residential Rate Design Investigation, Report prepared for Hawaiian Electric and Light Company.*
6. *Orans, R., C.K. Woo, and B. Horii (2004-2005) PG&E Generation Marginal Costs, Direct and rebuttal testimonies submitted to the California Public Utilities Commission on behalf of PG&E.*
7. *Orans, R., C.K. Woo, B. Horii, S. Price, A. Olson, C. Baskette, and J Swisher (2004) Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, Report prepared for the California Public Utilities Commission.*
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11. *Horii, B., C.K. Woo, and S. Price (2001) Local Integrated Resource Planning Study for the North of San Mateo Study Area, Report prepared for PG&E.*
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30. *Horii, B., (1991) Pacific Gas and Electric Company 1991 Electricity Cost Adjustment Clause Application (Revenue Allocation and Rate Design), Submitted to the California Public Utilities Commission.*

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3. *Orans, R., C.K. Woo, B. Horii and R. Pupp, (1994), "Estimation and Applications of Area- and Time-Specific Marginal Capacity Costs," Proceedings: 1994 Innovative Electricity Pricing, (February 9-11, Tampa, Florida) Electric Research Power Institute, Report TR-103629, 306-315.*
4. *Heffner, G., R. Orans, C.K. Woo, B. Horii and R. Pupp (1993), "Estimating Area Load and DSM Impact by Customer Class and End-Use," Western Load Research Association Conference, September 22-24, San Diego, California; and Electric Power Research Institute CEED Conference, October 27-29, St. Louis, Missouri.*